Introduction
Recent bidding rounds announced by the Mexican authorities resulted in renewed exploration interest within the offshore deep-water Campeche area, Gulf of Mexico. Deep-water Campeche is characterized by the abundance of salt diapirism and elevated carbonates due to severe thrusting triggered by regional tectonics that peaked at Middle Miocene time. Understanding variations in pore pressure and rock stress is beneficial to both seismic imaging and exploratory drilling, especially in subsalt regions where seismic illumination is poor and signal-to-noise ratio is low. Herein, the pore pressure and rock stress can be effectively estimated using the first principles of mechanical compaction and Darcy’s law through 3D basin modeling (Hantschel and Kauerauf, 2009).

Setting
Campeche deep water (highlighted in red in Figure 1(a)) is located in the southern Gulf of Mexico, approximately 100 km from the coast of the Tabasco and Campeche states of Mexico. The study area has a complex tectonic history from the middle Jurassic to the present day. It is characterized by severe folding, due to compressional episodes occurring through the Neogene period, deep-rooted thrust faults (Figure 1(b)), and shallow allochthonous salt canopies and carbonate rafts (Figure 1(c)), which introduce challenges for earth model building, but also create excellent trapping conditions for oil and gas accumulations.

Figure 1 Geological setting of Campeche deep-water basin. (a) study location, (b) fault framework, and (c) Seismic data with interpretation after restoration work: Auto and allochthonous salt (purple), pre-salt siliciclastics (dark purple), in-situ and raft cretaceous (blue), post-salt siliciclastics (green and yellow).

Workflow
The workflow includes seismic interpretation, structural restoration, and lithofacies interpretation to build the present-day earth model; followed by basin modeling that includes facies piercing and replacement setup, boundary conditioning, simulation and calibration procedures. Structural restoration was performed to reduce the uncertainty of the initial interpretation and to better understand the deformation history.

Facies piercing and replacement was employed for the basin modeling to simulate the effect of thrusting and salt tectonics accompanied by allochthonous salt movement and carbonate rafting in the study area. In this process, all the allochthonous salt movement and carbonate rafting were treated as vertical movement only. This is carried out by generating a paleo-model prior to the facies piercing; the model was then replaced with piercing facies progressively through geological time based on the understanding of the tectonic episodes in the region. In settings of severe thrusting and lateral shortening such as the study area, a palinspastic-type of reconstruction through a full-scale 3D restoration proceeding to basin modeling would be an alternative approach (which would be aligned with the restoration result). However, the latter workflow requires creating multiple paleo-earth models in addition to constructing the present-day earth model, which is time-consuming, and also with high uncertainties in the paleo-earth models.
Present-day earth model, facies piecing and replacement

The present-day model was generated in two steps: chronostratigraphic framework construction and lithofacies population. The chronostratigraphic framework was built based on interpreting major stratigraphic formation tops. A total of eight horizons were interpreted, starting from the seafloor, and working down through tops of Middle Miocene, Oligocene, Eocene, Cretaceous, top and base of autochthonous salt, and the basement. Over 90 major faults in the study area were also interpreted. A simple grid model was created using the interpreted formation tops and faults with a cell size of 200 x 200 m and 107 sublayers, totaling ~14 million cells. Five major lithofacies were categorized based on regional petrophysical analysis. These are shale, siltstone, sandstone, carbonate (in-situ and raft), and salt (autochthonous and allochthonous). Population of the lithofacies in 3D is based on both geological interpretation and the volume of shale (Vsh) attribute estimated from reflection seismic amplitude. The salt and carbonate were based on interpreted geobodies. Shale, siltstone, and sandstone were defined based on Vsh thresholds (left image in Figure 2). A paleo-model was also built to represent the earth before the thrusting, salt intrusion, and carbonate rafting. The facies allochthonous salt and carbonate raft were replaced by siliciclastic facies (shale, siltstone, and sandstone) using sequential indicator facies simulation (right image in Figure 2). Based on the understanding of the regional tectonic episodes and considering the number of sublayers and associated thickness, a replacement scheme was defined that includes 11 time-steps (from 12 to 2.5 million years) to mimic the piercing process.

![Figure 2](Basin modelling that includes present-day facies model on the left, and, facies piercing and replacement model on the right.)

Basin modelling and calibration

Although significant shortening was observed in the seismic data, regional tectonic stress was ignored in the study due to lack of a definitive regional tectonic stress model, assuming gravity was the sole source of the rock stress. The paleo-water depth (PWD) (Figure 3 1(a)) was created based on the depositional environment of the lithologies inferred from petrophysical analysis. The sediment water interface temperature (SWIT) (Figure 3 1(b)) was calculated based on the PWD and paleo-latitude following Beardsmore and Cull (2001) and using a global mean temperature model at sea level based on Wygrala (1989). The paleo-heat flow (Figure 3 1(c)) was created using the crust thickness model in the region and reaches the highest value of 81 mW/m² during the syn-rift, and then levels off to 30 mW/m² at the present day.

The results of the basin modeling were calibrated in terms of density (overburden), pore pressure (mud weight), and temperature data at the location of Well A. Consistent trends were obtained between the simulation results and well data after multiple iterations during the calibration process as shown in Figure 3 2. The modeled density (Figure 3 2(c)) follows the trend of the measured density at the depth where the density log is available. The modeled density shows a regression below ~2000 m that corresponds to a pressure build-up from increases in mud weight (MW) and fracture gradient observed at Well A (Figure 3 2(b)). Based on the well report, the actual formation pressure was thought to be lower than the MW used at interval ~4000 m. For this reason, the simulated pressure was calibrated to
lower values than MW data at the interval. The simulated temperature is calibrated to the measured formation temperatures as shown in Figure 3 2(a).

Figure 3 Boundary conditions on the left and calibration on the right.

Results synthesis
Simulated pore pressures (in pounds per gallon [lb/gal], ppg) at major formation tops are shown in Figure 4. Quasi-hydrostatic pore pressure is revealed for the Neogene sediments at shallow depth (Figure 4(a)). The pressure then builds up throughout Paleogene and below (Figure 4(b), 4(c), 4(d)), reaching 16ppg and over at top of the Cretaceous (Figure 4(d), 4(e)). These pore-pressure maps show a consistent lower-pressure trend in the northwest highlighted in blue of Figure 4(e), and higher pressures southeast in the subsalt canopy region highlighted in red of Figure 4(e).

Figure 4 Pore pressure gradients at major formation tops.

The increases in pore-pressure gradient, mostly over 16 ppg, at structural highs on the southeast (Figure 4(e)) may be explained by the centroid effect. A word of caution is given here. Based on the simulation, the actual pore pressure gradient at these structural highs might be even higher if they were hydrocarbon-charged and they may reach 17 ppg or higher because the effect of hydrocarbon generation was not modeled in the current work.

Variations in estimated stress vectors of Sigma-2 and Sigma-3 (Figure 5) are sensitive to the shape of the salt and the occurrence of the fault. Observe the tress rotations along the salt boundaries, and both sides of the faults. The absolute magnitude and direction of the stresses may be altered, should a major tectonic stress trend exist in the study area because the modeled results assumed zero regional stress in the boundary condition specifications. However, the estimated stress fields can be used more in a relative sense.
The source-rock maturity overlay (vitrinite reflectance) at the major formation tops (Figure 6) indicates that the regional source-rock interval began maturing for oil in the deep sags on the west below the Oligocene (Figure 6(b)). The shales are mature for oil in most of the sags on the west below the Eocene (Figure 6(c)) and the shales are mostly mature for oil below the Cretaceous (Figure 6(d)). Tithonian shales, the most important source rock of the region, are mature for oil throughout most of the area, and mature for gas in sags at the southwestern corner as highlighted in red (Figure 6(e)). The Tithonian shales maturity pattern is congruent with findings of exploratory activities in the region.

Figure 5 Principal stress vectors around allochthonous salt and faults.

Figure 6 Present-day Maturity (Ro%) at major formation tops.

Conclusions
High pressures, over 16 ppg, were modeled in most of the subsalt areas in the south at structural highs on top of the Cretaceous level. The actual pressure may reach 17 ppg or higher if these structures are hydrocarbon charged. The modeling also reveals an overall quasi-hydrostatic pressure for the shallow Neogene sediments. A rock maturity map of the Tithonian shales indicates that the shales are mature for oil throughout most of the study area and mature for gas only in deep sags in the southwestern corner. The study also shows that facies piercing and replacement can be a reasonable simplification of salt movements and carbonate rafting due to thrusting and diapirism.

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References